Energy for generations

ESB GT's response to

Ofgem's Call for Input on

Locational Pricing Assessment

24/06/2022

1. INTRODUCTION

This submission presents ESB Generation and Trading's ("ESB GT") response to Ofgem's consultation on Anticipatory Investment and Implementation of Policy Changes. ESB GT welcomes this opportunity to discuss this important topic.

ESB's portfolio in Great Britain includes a combined-cycle gas turbine plant in the northwest, offshore wind farm interests in Scotland, and a growing onshore wind presence. A central feature of ESB's business is to deliver benefits to consumers by investing in the most efficient renewable assets, particularly offshore and onshore wind at locations where the wind resource is highest. Naturally, it is important for the rules to facilitate investments at locations where the energy yield is economically viable for these renewable assets.

By way of an introduction, ESB is Ireland's foremost energy company, with around 7,000 employees. Established in 1927 by the Irish Government, and remaining 95% state owned, ESB created the first fully integrated electricity system in the world. ESB owns the transmission and distribution systems in Ireland and Northern Ireland. ESB have been present in Great Britain since market liberalisation and for 25 years has powered homes and businesses across the country, investing around £2 billion. ESB was one of the first IPPs in the UK with our investment in Corby Power Station (350 MW) in the early 1990's.

ESB is supporting Britain's transition to a low carbon future by investing in flexible and renewable generation assets, including combined-cycle gas turbine, wind, and biomass technologies. ESB opened Carrington Power Station (880 MW) in 2016, one of the most flexible and efficient plants in the market on the site of an old coal plant near Manchester. This was the first large-scale gas-fired station to come on stream in Great Britain since 2013. Carrington is owned by ESB's 100% subsidiary Carrington Power Limited. ESB also owns 125 MW of onshore wind generation capacity (with over 1,400 MW in the development pipeline across the UK), a 7 MW battery storage project in Lincolnshire, and recently invested in the 353 MW Galloper offshore wind project.

2. RESPONSES

This response considers three questions:

1 The key opportunities associated with introducing more granular locational pricing in GB;

2 The key implementation challenges, risks, and mitigations; and

3 The proposed approach to modelling zonal and nodal market designs.

2.1 The key opportunities associated with introducing more granular locational pricing in GB

The key opportunities associated with more granular locational pricing in GB have been explored in some detail by FTI Consulting as part of the National Grid Electricity System Operator ("NG ESO") Net Zero Market Reform programme[1]. This study has concluded that there are benefits for the ESO to move to nodal pricing. Nodal pricing would most probably lead to a reduction in system constraint costs as congestion costs are incorporated into the wholesale price at each node, removing the need for NG ESO to provide constrained-off payments.

It is also claimed by FTI Consulting that centralised dispatch, supported by nodal prices, is likely to support more efficient dispatch, make full use of all available resources, and fully utilise the capacity of the transmission system. Other potential benefits of nodal pricing include transparent and understandable prices and to facilitate sharper and more accurate price signals that help the Demand Side to realise its full value.

However, on the downside, nodal pricing:

- Is more complex and computationally demanding – this has been demonstrated in the Electric Reliability Council of Texas ("ERCOT") model of nodal pricing.
- There is no single national price for contracts and risk management – no liquid national market creates basis risk for generators and hedging risk for suppliers. This may affect investment decisions and increase the cost of capital.
- Puts the cost of renewables penetration onto generators rather than onto network development. This may also affect investment decisions and impact the delivery of Net Zero by 2050.
- Creates uncertainty over what happens at Distribution level – how and when will locational pricing be introduced at the Distribution level?

[1] NGESO Net Zero Market Reform – Part 3 (April 2022)

- Leads to uncertainty in how historic interventions will be reflected in future incurred costs.
- May lead to local prices not being charged to local consumers and/or may create a divide based on historical investment patterns of the Transmission System Operator ("TSO").
- May send perverse signals to renewables or low carbon developers that create an investment signal that offsets the TSO's network investment needs but does not optimise the investment where fuel is available e.g. wind in Scotland and offshore locations.

A zonal market designed along the main boundary constraints could improve dispatch outcomes and/or system cost outcomes relative to a national market. However, there will also most likely be a reduction in liquidity and the ability to hedge risk compared to a national market. A zonal market would not account for the transmission line limits within zones and the dynamics of participants in multiple nodes seeking to flow power across zones.

There are issues with zonal pricing – the key one being how the zones are set and how they may need to develop as generation and demand changes. Intra-zonal congestion may also be a problem. The degree of complexity required for a transition to a zonal approach would be much less than that required for nodal pricing however, there are still significant disadvantages with such an approach as discussed above.

Problems have been encountered in some markets such as in Texas where the shift from zonal to nodal market structure was controversial, complicated, expensive, and took longer than expected. Problems had emerged shortly after launch of the initial zonal-based market and the nodal approach was offered as a solution. Despite the reservations of some market participants, ERCOT began the move to a nodal design. It took several years for ERCOT to actually complete the process. Jay Zarnikau, C.K. Woo, and Ross Baldick[2] studied the change to a nodal market and examined whether the shift from a zonal to nodal market design in the ERCOT power market had a noticeable effect on electric energy prices. Their analysis showed that prices fell only by around 2% in the new nodal pricing regime. Direct comparisons were difficult, however, as the prices are generated by the system had changed, making simple before and after comparisons unrepresentative. For example, rather than four zonal prices produced every 15 minutes, the nodal market yields thousands of prices every 5 minutes.

The TNUoS charging methodology, as an ex-ante capacity-based charge, has provided the locational signals for generation and demand to connect to the National Electricity Transmission System ("NETS") for over thirty years. By and large, TNUoS charging has worked well in

[2] Zarnikau, J., C. K. Woo, and R. Baldick. "Did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market?."*Journal of Regulatory Economics* 45.2 (2014): 194-208.

ensuring efficient operation and development of the NETS. We understand that the growth in renewable technologies such as offshore wind is causing some issues with the current charging methodology. However, the NG ESO is setting up a TNUoS Taskforce to evaluate the TNUoS charging methodology and **Ofgem should take any outcomes from that assessment into consideration in its call for evidence of location marginal pricing ("LMP")**.

2.2 The key implementation challenges, risks, and mitigations

The transition from the current national market to a nodal/zonal market design is likely to introduce a potential set of costs and benefits for market participants and consumers. According to FTI Consulting[3], "locational market reforms, despite the potential benefits, are expected to be costly". The complexity of delivering locational reform will incur ESO system implementation costs, including one-off costs to enhance the processes, new IT and software systems plus additional unexpected higher costs, and extended timeline delivery risks. FTI Consulting estimates the costs, based on its international review, of between £32m and £75m. For individual market participants, the one-off costs to update systems and capabilities are thought to be between £50k and £600k depending on experience.

Moving to a centralised dispatch supported by nodal prices from self-dispatch in a national market is also likely to carry some risk for generation plant operators in that their systems and operational procedures are set up for self-despatch. One of the key drivers for moving to a central dispatch market design is that it is supposed to enable the system operator to manage high volumes of intermittency on a system-wide basis. However, this may reduce the economic flexibility of intermittent sources of power and reduce the attractiveness of investing in the GB electricity market.

The timeframe for transitioning to a nodal design depends predominately on the efficiency of the stakeholder engagement and can take between 4–8 years according to FTI Consulting/NG ESO's analysis. We note that these reforms are likely to have a wide distributional impact which will need to be assessed through more detailed Cost Benefit Analysis. Issues such as uncertainty around how historic interventions will be reflected in costs which will be incurred will need to be addressed. Several measures could be used to smooth the transition and provide market participants with time to adjust, such as grandfathering and aggregated pricing for suppliers.

[3] Net Zero Market Reform - Phase 3: Assessment and Conclusions Publication, NGESO (March 2022)

The TNUoS Task Force that will be formed in the later part of 2022 aims to 1) identify the root causes of unpredictability of TNUoS charges and 2) ensure that the locational element of TNUoS charges remain cost reflective. The TNUoS Task Force explicitly excludes market-related changes such as LMP. A potential challenge is the coordination between the two distinct work streams to encourage investments at locations that would reduce congestion in the transmission network.

The idea that nodal pricing would resolve congestion issues through a market clearing process may not be optimal because a price equilibrium would be required and consequently, a prolonged iterative price discovery process with no enduring investment signal. Relying on the ESO to re-dispatch to ease congestion is not an enduring solution especially with more intermittent generation cumbersome and may not include all supply-demand factors. A counterfactual to these points is the likely reduction of constraint payments by NG ESO to generators compared to the expected increases in wider TNUoS tariffs. In other words, will nodal pricing reduce constraint payments but increase the wider TNUoS tariffs? Using price to determine if a generator should operate may not be the best utilisation of renewable generation. It is unclear at this stage if nodal pricing would mitigate the fundamental issue of supply and demand. For example, offshore windfarms located in the remote areas of GB may not have sufficient demand within its node. Power will need to be exported to other demand centres and the offshore windfarm will incur transmission charges.

Intermittency from renewables requires some form of energy storage to account for periods of “high generation with low demand”. Clarity is needed as to how nodal pricing will account for a storage facility importing power during periods of “high generation with low demand”. Parallels could be drawn with how transmission charges into gas storage facilities are reduced by 50% to account for the subsequent dispatch where the remaining 50% would be charged. Essentially, the issue of storage facilities within a node needs to be addressed as well as the mechanics of a “secondary market” within a node.

2.3 The proposed approach to modelling zonal and nodal market designs

We are in broad agreement with the proposed approach to modelling zonal and nodal market designs. The definition of the zones will be crucial, and we acknowledge that there are issues such as how intra-zonal congestion would be resolved. The modelling of nodal pricing will depend on how nodes are defined. The outcome of the TNUoS Taskforce should also be considered in how locational signals can be delivered through the charging methodology and whether this might preclude the need to move to locational marginal pricing. Other issues need to be considered, such as: the context of delivering the net zero transition; the savings in carbon; the cheaper fuel and reduced cost in wholesale markets on a wider market rather than a regional market; the welfare value; and the value of offshore to all consumers not just local consumers.

We are also aware of other potential market studies which may look at an analysis of several options such as the Status Quo, Status Quo Plus and zonal and nodal alternatives. We believe that these should also be considered.

3. CONCLUSIONS

ESB GT has a number of existing assets and a number under development. These investment decisions have been made based on the current market arrangements – we are concerned that a fundamental market re-design could affect the financial viability of these investments. We are concerned about the uncertainties during a market re-design, which could take 4–8 years. There is also uncertainty around the final arrangements and how costs and risks may be transferred between parties. We acknowledge that there are issues with the current market design but there also a number of advantages with it such as having a national price to hedge against. The current market design is also well understood by investors. We are also concerned about the complexity of a nodal market and the computational tools required to participate in such a market. However, we remain fully committed to working with Ofgem, NG ESO, and other stakeholders to explore alternative market designs.